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Optimal investment in electric generating capacity under climate policy

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ABSTRACT

Mitigating climate change will require reduced use of fossil fuels to generate electricity. To do so while eschewing nuclear power, countries have turned to wind and solar energy. In this paper, load duration and screening curves are used to investigate the extent to which a jurisdiction should invest in intermittent (solar and wind) sources of energy, gas and nuclear power. The application is to the Alberta electricity grid because it is nearly 90 percent reliant on fossil fuels, particularly coal, and recent policy intends to eliminate coal generating capacity by 2030 and replace two-thirds of the lost capacity with renewables. Results suggest that solar and wind are unable to replace two-thirds of coal generation, and that larger than anticipated investments in natural gas capacity will be required. However, if Alberta is serious about reducing emissions, it will need to rely on nuclear energy; at high carbon prices, nuclear power could reduce CO_2 emissions by some 95% compared to only 55% when relying totally on solar and wind.

1. Introduction

Following the December 2015 Paris Agreement, Prime Minister Justin Trudeau emphasized the key role that provincial and territorial governments have in helping Canada achieve its ambitious carbon emissions targets (Office of the Prime Minister, 2015). While the majority of Canadian provinces and territories have kept their greenhouse gas (GHG) emissions in check over the past 25 years, Alberta's emissions have risen to 273.8 megatonnes (Mt) of carbon dioxide equivalent (hereafter just CO_2) as of 2014 – an increase of roughly 56% since 1990 (ECCC, 2012) and now more than a third of Canada's overall emissions. This is because Alberta is Canada's energy producer, with CO_2 emissions forecast to rise to 320 Mt by 2030 under business-as-usual assumptions. For Canada to reduce its GHG emissions will require Alberta to rely on renewable energy to a greater extent.

The bulk of Alberta's CO_2 emissions come from its oil and gas industry, with lesser contributions from sectors such as agriculture and transportation. Oil and gas are large carbon emitters, but are designated as trade-exposed under international regulations, because policies aimed at reducing emissions in these industries may only serve to locate them elsewhere. However, nearly one-fifth of Alberta's emissions come from electricity generation, which is a target for emissions reduction, unlike the trade-exposed industries (Leach et al., 2015). In 2016, 62% of Alberta's power was generated by coal-fired power plants, but these are now to be decommissioned or converted to gas by 2030 with two-thirds of lost coal generating capacity to be replaced by renewable sources (Alberta Government, 2016). As natural gas supplied 27% of Alberta's electricity needs in 2016, fossil fuel generation dominates the provincial power grid.

A stumbling block in the development of renewable energy is the intermittent nature of solar and wind sources. Because of its intermittency, wind and solar cannot be considered reliable as either base-load sources of electricity or suitable for addressing peak demand (van Kooten et al., 2016), and thus the integration of renewable energy into the grid has proven problematic for many countries (Timilsina et al., 2013). If the Alberta government intends to integrate renewable energy into its grid to the extent that renewables replace two-thirds of coal-fired power,[1] some form of energy storage might be required to maintain a reliable power supply throughout the province. At this stage of development, however, the only realistic storage is hydro capacity; Alberta has little hydro storage, while trade with British Columbia, which has significant hydro storage capacity, is limited (Sopinka et al., 2013). Given the time frame for Alberta to achieve its policy of eliminating coal-fired power, we only consider the potential challenges that Alberta faces by switching to renewable energy and gas sources for electricity. After all, Alberta does have some of the best wind and solar regimes available anywhere in Canada, and these should be sufficient to enable the province to achieve its short-term objectives.

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[1] Replacing two-thirds of the lost coal capacity with wind and solar capacity is easier than replacing 2/3 of lost coal generation with power from wind and solar. In our analysis, we discuss both these situations.

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The purpose of this study, therefore, is to investigate the potential to use energy from intermittent wind and solar sources, along with energy storage, to meet Alberta's goal of eliminating reliance on coal power without having to replace more than one-third of the lost coal capacity with natural gas. To do so, we employ a mathematical programming model that optimizes the mix of generating assets subject to technical and policy constraints. The policy model is provided in section 2, followed in section 3 by a description of the Alberta study region. A discussion of our results is provided in section 4; these indicate that, even using a very simple model, the complications of integrating intermittent resources into an existing grid require the installation of greater gas generating capacity than desirable.

1.1. Model for choosing optimal mix of generating asset types

There are two means to determine the optimal investment in various types of generating capacity: the classical screening curve method (Stoft, 2002, pp.33–39; Joskow, 2006; van Kooten, 2016; Güner, 2018) and the merit-order stack approach (Staffell and Green, 2016).[2] The screening curve method for determining the optimal investment in generating capacity is illustrated using Fig. 1, with the vertical axis in the lower portion giving the merit order of loading. However, since this method has difficulty addressing the optimal investment in renewable capacity, among other things, a modification of this approach is applied using a policy-oriented mathematical programming model. Both approaches are outlined in the following subsections.

1.2. Screening curves and optimal investment in capacity

The screening curve for generating asset g can be stated mathematically as:

$$C_g(h) = (fc_g + fom_o) + vc_g \times h_g, \tag{1}$$

where C_g is the total cost incurred to operate the asset for one year or, considered from another perspective, the annual revenue required per unit of capacity (MW) for generator g; then fc_g is the annualized capital cost, fom_g refers to the annual fixed operating and maintenance (O&M) costs, vc_g is the variable cost component (slope of the screening curve), and h_g is the duration (measured in hours per year) that asset g will generate power. The annualized capital cost (fc) is:

$$fcg = on_g \times \frac{r \times (1+r)^{T_g}}{(1+r)^{T_g} - 1}, \tag{2}$$

where on_g is the overnight construction cost ($/MW), or the cost of all material, labor, fuel, etc., needed to construct facility g if that cost was incurred at a single point in time; T_g is the economic life of the plant; and r is the discount rate.

The vertical-axis intercept of screening curve g is the annualized capital cost fc_g plus the annual fixed component of O&M costs fom_g in equation (1). The slope is determined by the variable operating costs, of which fuel costs are usually the most important. The variable fuel cost is expressed in $/MWh and is converted to the same units as the fixed cost component ($/MW) by multiplying by expected operating hours (Stoft, 2002, pp.34–35). Since the lifetime of a power plant generally ranges from about 20 years for wind turbines to 50 years or more for coal plants, the intercept and slope of a screening curve are based on expectations concerning upfront capital costs, annual O&M costs, operating hours and future fuel prices.

As indicated in Fig. 1, the screening curves and their intersection, along with the load duration curve, determine the optimal mix of generating assets (Joskow, 2006; Stoft, 2002). The optimal capacity is related to the number of hours of the year that a generator is expected to operate. Thus, a coal plant is expected to deliver power to the system for 7450 h or more, or about 85% of the time. A peaking plant might operate no more than 1800 h annually (≈ 20%), but hours are not contiguous so it needs to ramp up and down quickly, and/or start up and shut down frequently. Some peaking plants might operate for less than 50 h per year.

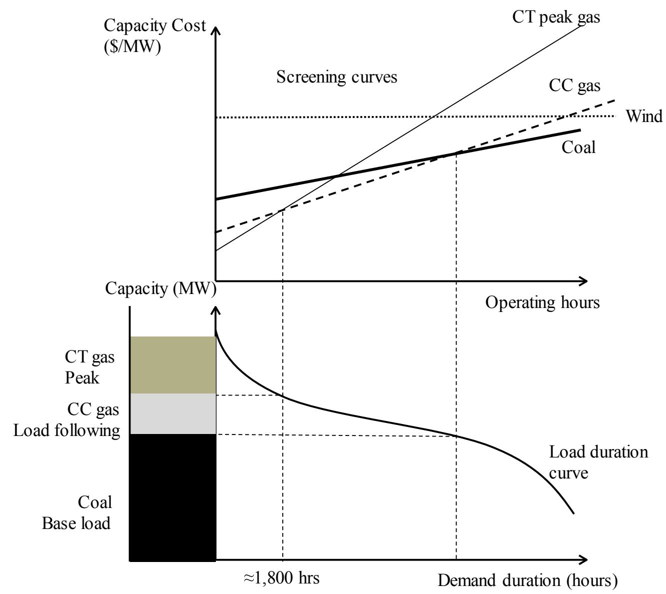

Fig. 1. Use of screening curves to determine optimal investment in generating capacity.

The generation type with the lowest overnight (capital or construction) cost is also the type that usually has the highest operating costs (screening curve with greatest slope), because it functions for short periods providing peak power. Such assets tend to be an open cycle, combustion turbine (CT gas) generators that operate much like a diesel or jet engine: by providing more fuel (applying pressure to the 'gas pedal'), the engine (which might be idling) immediately speeds up generating more power; by providing less fuel, the engine's power is reduced in direct proportion to the reduction in fuel.

In contrast to CT gas, a combined-cycle gas turbine (CC gas) facility not only uses the turbine's spinning blades to generate power but also employs the excess heat that would otherwise be wasted in a CT gas plant to fuel a boiler that generates additional electricity. A CC gas facility is expected to operate for longer periods since, in contrast to CT gas, it is difficult to increase or reduce power rapidly as the boiler takes longer to gain or lose pressure and thus heat. As a result, CC gas plants provide baseload and load following services, not peak-load output.

Coal-fired and nuclear power plants have the highest construction costs but the lowest fuel costs. Such facilities are expected to remain in continuous operation throughout the year, only shutting down for routine maintenance or unexpected outages.

Overnight costs of installing wind turbines or solar panels have generally been higher than those of gas and coal plants, but have been falling over time; the same is true of their fixed O&M costs. The major drawbacks of wind and solar energy sources are intermittency and unreliability, which lowers their capacity factors; this makes these renewable sources of electricity unsuited for providing baseload power. The screening curve approach to investment planning is unable to address investment in intermittent, renewable energy sources.[3] Further,

[2] Güner (2018, pp.324–325) provides a review of the classical screening curve method for determining an optimal generation mix, while Staffell and Green (2016) indicate that today's screening curve method is a variant of the merit-order stack approach. As noted by a reviewer, Palmintier and Webster (2011), and Koltsaklis and Georgiadis (2015), provide alternative perspectives.

[3] As an energy source for generating electricity, biomass does not suffer from intermittency, but it remains controversial, partly because it is not carbon neutral (Johnston and van Kooten, 2015).

this approach to investment planning is static (demand is assumed to be invariant), deterministic (e.g., cannot take into account unit unavailability), ignores transmission, and is unable to address investment in intermittent, renewable energy sources (Güner, 2018, p.312). It also assumes no generating mix of assets is already in place.

The problem of intermittency makes it difficult to determine optimal investments in various types of generating capacity (Lamont, 2008; Güner, 2018). The introduction of non-dispatchable or 'must-take' wind generated electricity into the market results in increased variability that potentially requires traditional generating assets to ramp up and down more quickly than previously, leading to increased costs, greater need for peak resources and reserves, and lower returns to existing plants. This is illustrated below.

Investment in Intermittent Assets: A Model to Determine Optimal Generating Capacity.

In this section, we employ a modified version of the screening curve method. The objective of the system operator is to minimize the costs of generating power to meet hourly load (Lamont, 2008; van Kooten et al., 2016):

$$\text{Minimize } C= \sum_{j=1}^{J} fom_j\, K_j + \sum_{h=1}^{H}\sum_{j=1}^{J} (v_j + \tau\phi_j) G_{h,j} + \sum_{j=1}^{J} (fc_j - d_j)\Delta K_j, \tag{3}$$

where, as above, fom_j and v_j refer to the annual fixed O&M costs (\$/MW) and variable O&M plus fuel (\$/MWh) costs, respectively, of producing power using generating asset j and there are J types of assets available; $G_{h,j}$ refers to the power generated in hour h by asset j (a decision variable); and H is the number of hours in a year (usually 8760). A carbon tax τ (\$/tCO_2) is a policy variable used to incentivize generation from wind and solar sources, while φ_j is the CO_2 emitted when producing a MWh of power from generation source j (and depends on the fuel source). Finally, K_j (MW) is the existing capacity and ΔK_j (MW) is the change in the capacity of asset j (decision variable), with capacity additions/removals assumed to occur instantaneously so that decisions concerning ΔK_j are effectively decisions concerning K_j.

Since we assume an existing set of assets, fc_j is the annualized cost of adding capacity, while d_j refers to the annualized cost of decommissioning assets (\$/MW). Including d_j in the objective function as a cost would not ensure decommissioning, however; assets would not be eliminated but simply left unused. Rather, in the objective function as written here, the cost of decommissioning assets is taken as a benefit (reducing cost) to ensure that decommissioning actually occurs; it is sufficient to ensure this by setting $d_j = 1$ and make an appropriate ex post adjustment to the objective function to obtain its true value (as discussed below).

In each hour, the electricity produced by all of the assets in the system must exceed the load for that hour, L_h. A rearranged form of this expression is:

$$L_h \le \sum_{j=1}^{J} G_{h,j},\ \forall h \tag{4}$$

We consider a 'black-box' battery so that, when it is included in a scenario, discharge from the battery, denoted B_h^-, can be used to meet load. At the same time, any excess wind, solar or baseload generation – the latter because it cannot easily ramp down generation[4] – can be sent to recharge the battery, which we denote by B_h^+. Then (4) is rewritten as:

$$L_h \le B_h^- - B_h^+ + \sum_{j=1}^{J} G_{h,j},\ \forall h \tag{5}$$

The dynamic component of the model is found in the ramping up and ramping down constraints for fossil fuel assets, since solar photovoltaic (PV) and wind generators are non-dispatchable and incapable of ramping up or down, and in the operation of a battery. The ramping up and down constraints are, respectively,

$$G_{h,i} - G_{(h-1),i} \le K_i \times R_i,\ \forall h, i \tag{6}$$

and

$$G_{h,i} - G_{(h-1),i} \ge -K_i \times R_i,\ \forall h, i \tag{7}$$

where R_i is the proportion of the capacity of asset i ($i \in$ {CC gas, coal, nuclear} $\subset j$) that can be ramped in each hour. Further, a generating asset cannot produce more than its nameplate capacity:

$$G_{h,j} \le K_j,\ \forall h, j \tag{8}$$

The operation of the battery requires that the energy in the battery at any hour, B_h^E (MWh), is determined by charge and discharge:

$$B_h^E = B_{h-1}^E + v\, B_h^+ - B_h^-,\ \ \forall h \tag{9}$$

where v is a parameter that gives the round-trip efficiency of the battery and the battery's capacity in the first hour, B_1^E , is given. Further, discharge cannot exceed what is available in the battery at any time:

$$B_h^- \le B_h^E,\ \ \ \forall h \tag{10}$$

Finally, there are the non-negativity constraints:

$$G_{h,j},\ K_j,\ B_h^+, \forall_h^E \ge 0,\ \forall h, j \tag{11}$$

2. An application: Alberta electricity grid

Currently 89% of Alberta's electricity is generated from coal and natural gas, with renewable sources accounting for the remainder including 7% from wind. Alberta has a long history of utilizing wind energy to generate electricity; its largest wind farm was built in 1993 near Pincher Creek (an area known for its strong winds). The Canadian Wind Energy Association (CanWEA) notes that, while Alberta has an installed capacity of nearly 1500 MW (MW) of wind energy, at least 4000 MW of new wind generating capacity will need to be built to make up for the anticipated loss in coal capacity by 2030 (CanWEA nd). Similarly, the Alberta Electric System Operator (AESO) anticipates that removal of coal-fired capacity will lead to 4200 MW of new wind capacity (see Table 1).

The solar PV energy market is not yet well-developed in Canada, although solar energy has great potential in Alberta (Hastings-Simon, 2016). While the AESO did not factor in increases in solar capacity in its 2016 analysis of how to replace loss of coal-fired power (AESO, 2016), solar PV was deemed significant in a subsequent analysis (Table 1). Alberta uses a carbon tax and regulation to reduce its CO_2 emissions from power generation. It does not employ feed-in tariffs and likely does not need to do so because of its excellent wind regimes. At this stage, the carbon tax is not scheduled to exceed \$30/tCO_2, but a tax of \$50/tCO_2 or even \$100/tCO_2 might not be inconceivable. Here we employ taxes of \$30 and \$100 per tCO_2, and for sensitivity analysis some higher values, while requiring coal capacity to be eliminated. This can be done by simply setting the intercept on the coal screening curve at some very large number.

2.1. Alberta load

The Alberta load duration curve for 2016 is provided in Fig. 2. It is almost identical in shape to the 2014 load duration curve.[5] We employ the 2014 load because the latest available wind and solar data are for 2014 (van Kooten et al., 2016). However, there is little difference

[4] A baseload generator operates each hour and is at full capacity at least 1 h (Lamont, 2008).

[5] A linear approximation of the 2016 load duration function is given by: D(h) = 10,560–0.342 h, $0 \le h \le 8784$.

Table 1
Current and anticipated changes in generating capacity, Alberta electric system (MW)[a].
Source: AESO (2017b).

Year	Coal-fired	Cogen	CC gas	CT gas	Coal-to-gas	Hydro	Wind	Solar	Other	Total
2017	6299	4934	1746	916	0	894	1445	0	479	16,713
2022	3849	5024	1746	1059	1581	894	3045	200	479	17,877
2027	2904	5114	2656	1249	2371	894	5045	400	479	21,112
2032	0	5204	5386	1486	2371	1244	6445	700	479	23,315
2037	0	5339	6751	2769	790	1244	6445	1000	479	24,817

[a] Future capacity as of the end of year, existing capacity includes under-construction projects.

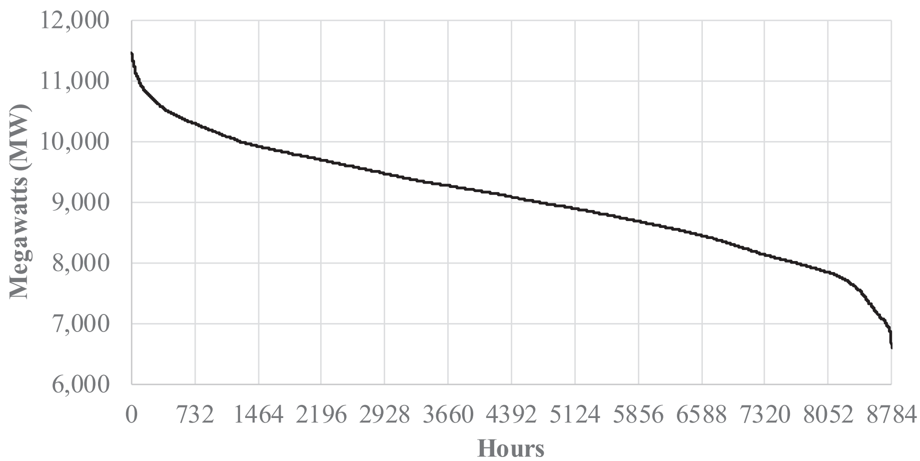

Fig. 2. Load duration curve, Alberta, 2016

between the two years: The respective base and peak loads were 6595 MW and 11,458 MW in 2016, compared to 7163 MW and 11,169 MW in 2014; 2016 was a leap year with 8784 h compared to 8760 h in 2014. Alberta's load profile is much flatter than that of other provinces, such as Ontario or BC, because of its relatively much larger industrial component.

2.2. Wind and solar energy and battery storage

We employ 2014 data for the Pincher Creek region in southwestern Alberta, because it has the best wind regimes and solar radiation profiles in the province (and among the best in Canada). Available mechanical energy (wind speed) data were converted to electricity based on the technical specifications for a 3.5-MW capacity Enercon E-101 wind turbine. The capacity factor (CF) of the resulting wind regime averaged 38.5% for 2014.[6]

Solar radiation data for Pincher Creek was converted to solar PV output using information for the Canadian Solar CS5P-220 M PV module with an area of 1.7 m^2, nominal efficiency of 12.92%, and generating capacity of 250 W. For our purposes, we define a panel of 20 modules that covers an area of 34 m^2 and has a generating capacity of 0.005 MW. Solar PV data for Pincher Creek for 2014 are thus normalized to a single such panel, with the decision to invest in generating capacity a decision to build a certain number of solar panels. For 2014, the CF for solar PV in the Pincher Creek was 17.2%, compared with 16.7% for Edmonton.[7]

It is important to distinguish between energy and power. Battery storage is measured in terms of energy, most often as megawatt-hours (MWh). The capacity of the battery is its ability to deliver power. For example, two batteries can deliver 10 MWh of energy, but one can deliver 5 MW of power, while the other only 1 MW; the first battery is emptied in 2 h, the second one in 10 h. In the model, we measure the energy stored in a battery without concern for its power; thus, if there is enough energy stored in the battery, we assume the battery can even deliver sufficient power to meet the province's peak load. We also assume that the cost of the battery is based on the maximum energy it needs to store in a year, regardless of the flux (charge and discharge) throughout the year, and that the round-trip efficiency of the battery is 95%.

2.3. Cost data

For our base case analysis, we employ six energy sources: coal, combined-cycle gas (CC gas), peak gas (CT gas), coal-to-gas (Cgas), wind and solar. Coal-to-gas refers to the option of converting coal generators to gas, with the AESO (2017b) indicating that up to 5400 MW (≈85%) of coal capacity could be converted and capable of operating for another 15 years. As for a starting mix of generating assets, we employed the data in the first row of Table 1, but, for simplicity, combining co-generation capacity with CC gas capacity, and ignoring hydro and other sources. The resulting fossil fuel generating capacity of 13,895 MW was sufficient to cover the peak load of 11,169 MW. Finally, we also consider scenarios with possible nuclear power.

The cost data used in the analysis are provided in Table 2. The data come from U.S. EIA (2016) and AESO (2016, 2017b).[8] Since variable O &M costs do not appear in U.S. data (U.S. EIA, 2016, p.7) and those provided by the AESO appear somewhat arbitrary (e.g., there are no variable O&M costs for wind or solar), only fuel costs are used. Further,

[6] More information about wind regimes is available from van Kooten et al. (2016). The average CF for wind regimes in other parts of Alberta is generally much less than 25%.

[7] CFs for Alberta solar PV tend to be higher than in most regions; for example, in Germany, they average about 12%.

[8] U.S. EIA cost data are not adjusted upwards for the exchange rate because costs for coal plants in western Canada are more like those in the western U.S., where land and mining costs, for example, are lower.

Table 2
Values of Screening Curves based on Alberta Data, $Cdn 2017.
Source: Authors' calculations

Generation Technology	Capital Costs[a] ($/MW)		Operating Costs[b] ($/MWh)
	Overnight	Annual fixed O &M	
Coal	$3,600,000	$52,500	$4.50
Combined cycle (CC) gas	$1,725,000	$27,000	$9.40
Simple cycle (CT) gas	$1,250,000	$18,000	$12.50
Coal-to-gas (Cgas)	$225,000	$22,000	$10.90
Wind	$2,000,000	$52,000	$0.00
Solar PV	$1,715,000	$46,000	$0.00
Nuclear	$5,945,000	$62,150	$2.15

[a] Data for coal and nuclear are based on U.S. EIA (2016); other data are from AESO (2017b). Averages of the high and low overnight construction cost estimates are employed. Coal plants are assumed to have a life of 50 years, gas plants 30 years, and solar and wind assets a life of 20 years; plants converted from coal to gas have a life of 15 years (AESO, 2017b).
[b] Based on average of projected fuel costs from AESO (2016, 2017b). For coal and nuclear, data are from U.S. EIA (2016).

because one expects gas to be used more efficiently in CC gas plants than CT gas plants, we arbitrarily pick the high price in the range provided by AESO (2017b) for CT gas and the low price for CC gas, with Cgas taken an average of these. Ramp rates for coal, CT gas, CC gas, Cgas and nuclear are assumed to be 2.5%, 80.0%, 15.0%, 30.0% and 1.5% of rated capacity per hour; the same rate applies for increases and decreases in output. Again, wind and solar assets are non-dispatchable.

The opportunity cost of using agricultural land for solar PV farms is initially ignored (see below), but, based on the data for a 0.005 MW-capacity panel, 1 ha covered with such panels would have a PV generating capacity of 1.47 MW, which implies 0.6 MW per acre. Using data from Liu et al. (2018) for Vulcan county near Pincher Creek, we find the average margin for dryland crops is $223.17/ac ($551.23/ha); assuming this is the land rental cost, it amounts to $371.95/MW (= $223.17/0.6).

For practical purposes, it is appropriate to make an adjustment to the annual fixed O&M costs for fossil fuel generators, because this adjustment represents the opportunity cost incurred by the system operator of removing assets. For example, if the annual fom_{coal} = $50/kW but the cost of removing coal generation is $15/kW, the shadow cost of retaining coal assets is $35/kW. Therefore, we reduce the annual fixed cost of the coal, CT gas and CC gas assets downwards by the avoided cost of decommissioning these assets, which we calculate as 15% of the annualized cost of construction for coal and 5% for gas assets; that is, the cost of dismantling existing facilities is a real cost. The final cost that we report does make a correction for this adjustment.

Finally, the cost of the battery is assumed to be a low $US 250/MWh (Healey, 2017). This is the price Elon Musk quoted in building a gigantic, 100 MW/129 MWh capacity (lithium-ion) battery in South Australia. Here and elsewhere we make no effort to take into account inflation or exchange rates as the Canadian and U.S. currencies were relatively close in 2014.

3. Results

The constrained optimization model is constructed in GAMS (General Algebraic Modeling System) and solved using the CPLEX solver (Rosenthal, 2008). Various scenarios are examined as discussed in this section. In the model, we allow the government to impose various values of a carbon tax to incentivize investment in wind and solar assets, but also gas plants, coal-to-gas conversions and eventually nuclear power; the carbon tax also incentivizes disinvestment in fossil fuel assets. Carbon taxes between $0/tCO$_2$ to $225/tCO$_2$ are considered, with the results discussed for three different cases: (1) no nuclear power and no coal to gas; (2) with and without nuclear power and permitting coal to gas; and, lastly, (3) no nuclear power but higher O&M solar costs to reflect the costs of renting land. Results are provided in Tables 3 and 4 and Figs. 3 and 4.

Table 3
Generation by Asset Type when No Nuclear Power Plants and No Coal-to-Gas Conversions are Permitted (TWh).

Carbon tax ($/tCO$_2$)	Coal	CT gas	CC gas	Wind	Solar
$0 (Base)	55.2	0.2	13.1	12.7	0.0
$30	4.4	5.6	58.4	12.7	0.0
$50	0.3	2.8	62.7	12.7	4.1
$75	0.1	1.9	62.7	12.7	6.4
$100	0.1	1.3	62.7	12.7	8.0
$150	< 0.05	0.8	62.7	12.7	10.1
$175	< 0.05	0.6	62.7	12.7	10.9
$200	< 0.05	0.5	62.7	12.7	11.5
$225	< 0.05	0.4	62.7	12.7	12.0

In the 2014 base scenario with no carbon tax, coal-fired capacity remains at its current level of 6299 MW (Table 1). The model finds that coal generates of 55.2 TWh of electricity throughout the year, representing 68% of total power generation (Table 3), compared to the 62% actually accounted for by coal two years later in 2016 (AESO, 2017a).[9] CT gas capacity also remained unchanged from its initial value, but the sum of co-gen and CC gas capacity was reduced from 6680 MW to about 2510 MW, mainly because our model does not take into account the difference between co-gen and CC gas and because there is excess gas capacity in the real system to meet ancillary requirements, particularly backup capacity in case a large asset fails. Ancillary services are not modeled because, other than hydroelectric dams and sometimes diesel, natural gas is the only available source for ancillary needs in Alberta. In the base scenario, gas accounts for 16.4% of generation (Table 3), compared to the actual 27% delivered by gas technologies in 2016. Wind capacity is also unchanged in our model when carbon is unpriced, with wind accounting for 15.6% of total generation, about double what it did in 2016; however, it is important to recognize that wind regimes can change significantly from one year to the next and that we do not model hydro and other (mainly biomass) generating assets (see Table 1).

Notice that, as the price of carbon (carbon tax) rises in Table 3, coal generation falls dramatically (even at a carbon price of $30/tCO$_2$), while CC gas production increases. In capacity terms, coal-fired capacity falls from approximately 6300 MW to 1980 MW at a carbon price of $30, and then to about 160 MW at the highest carbon prices; surprisingly, coal capacity is not driven entirely out of the system even though coal-fired generation is best measured in GWh rather than TWh once the carbon price exceeds $30/tCO$_2$. When the carbon price is $30, coal-to-gas conversions are optimal and preferred to investment in wind or solar assets – when coal-to-gas conversions are not permitted, solar and wind do not enter. However, when the carbon price rises above $30, coal-to-gas conversions are no longer optimal investments compared to solar or wind (partly because such assets are so short lived). Meanwhile, CC gas capacity increases in the model from 2500 MW to about 6700 MW at a carbon price of $30 and then to 7200 MW at higher carbon prices. Peak CT gas capacity in the meantime climbs from 920 MW in the base scenario to 1400 MW at a carbon price of $75, but falls down to about 1000 MW at the highest prices as more and more solar power comes on stream.

No additional renewable wind or solar capacity is added to the system until the price of carbon reaches $50, when solar capacity (not

[9] Hydroelectric power is not included in the base-case scenario as it is non-dispatchable. The observed proportion of non-hydro generation accounted for by coal is some 65%, quite close to the 68% in the model's base case scenario.

Table 4
Average costs (AC) and marginal costs (MC) of Reducing CO_2 emissions in the Alberta electricity grid for various incentive levels, \$/tCO_2.

Carbon tax	Scenarios					
	No nuclear				Nuclear	
	Low solar O&M costs		High solar O&M costs		Low solar O&M costs	
	AC	MC	AC	MC	AC	MC
\$30	5.19	5.19	4.99	4.99	5.19	5.19
\$50	8.59	32.59	7.93	41.04	8.59	32.59
\$75	9.49	50.07	9.70	52.30	9.49	50.07
\$100	10.21	75.07	10.68	76.87	10.21	75.07
\$125	10.72	90.73	11.52	100.94	10.72	97.45
\$150	11.23	106.39	12.27	124.63	11.23	119.84
\$175	11.64	140.71	12.82	145.23	20.32	155.00
\$200	11.96	161.98	13.28	168.40	27.41	177.26
\$225	12.24	187.45	13.72	193.77	88.18	196.87

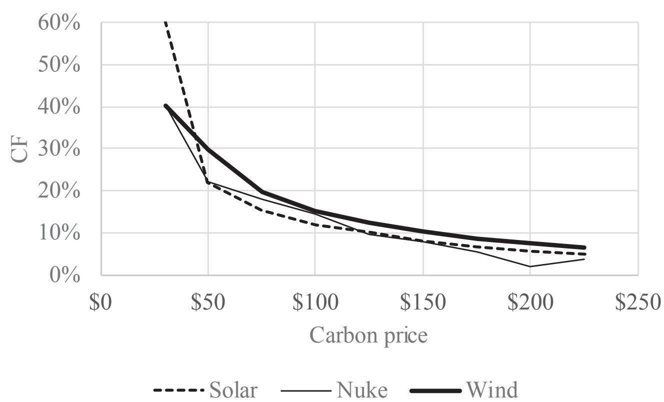

Fig. 3. Capacity factors for peak-load, gas turbines as carbon price increases; three scenarios.

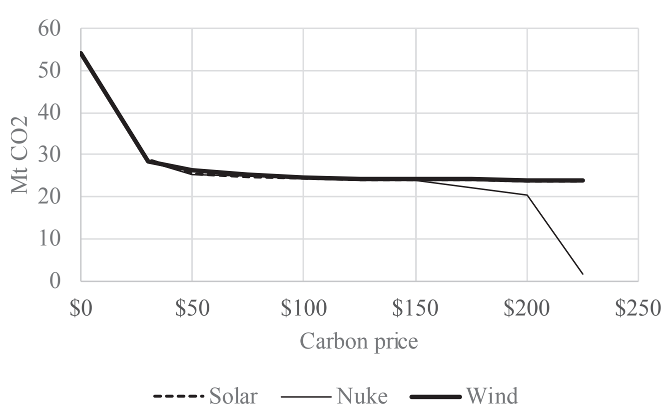

Fig. 4. CO_2 emissions for various non-fossil fuel scenarios, various carbon prices.

wind as the O&M cost of solar PV is lower) comes in at 470 MW and slowly rises to nearly 1400 MW at the highest carbon price. This only amounts to 32% of the lost coal capacity, and even less if all the coal capacity is removed. The government target of replacing two-thirds of coal capacity with renewables must be enforced or subsidized, since carbon prices are insufficient to incentivize investment in renewables.

From Table 3, it is clear that CC gas replaces coal as the baseload asset, with only 7.5 GWh of generation (or 13.6%) previously provided by coal replaced by some other source than CC gas: between 3% and 37% of generation comes from CT gas and the remainder from solar (with solar providing more of this proportion as the price of carbon increases). However, at most 22% of the power previously generated by coal is replaced by new investment in renewables. For the most part, solar energy will replace CT gas. Despite requiring significant CT gas capacity to maintain grid reliability, less power is generated from CT sources as more intermittent (renewable) energy capacity is built. This is seen by examining the capacity factors of peak-load gas plants (CT gas) in Fig. 3, where three scenarios are identified: solar (low solar O&M costs), wind (high solar O&M costs due to payment of farmland rents), and nuke (nuclear and coal-to-gas investment permitted). The figure demonstrates that, as more intermittent wind and/or solar power enters the grid, the CFs for peak-load gas plants decline.

The results suggest that it may be necessary to subsidize investments in peak-load capacity when intermittent renewables enter the system. The proportion of the time that peak plants operate is reduced and thereby, unless prices happen to be extremely high during operating periods, there tends to be under investment in peak-load gas plants. This is important in a system such as that of Alberta because prices are capped at \$999/MWh; thus, at times when market conditions warrant higher electricity prices, peak-load plants receive too low a price thereby losing quasi-rents necessary to pay for capacity investments, something that has been identified as the 'missing money' problem (Joskow, 2006). The 'missing money' problem is worsened in all three scenarios, because intermittent, non-dispatchable renewable energy displaces production by peak load generators.

System-wide CO_2 emissions in the 2014 base scenario are approximately 54 million tonnes (Mt), or about 7.4% of all Canada's greenhouse gas emissions that year. Now consider model estimates of the average and marginal costs of reducing CO_2 emissions in Alberta, which are provided in Table 4. Average costs of reducing emissions range from \$4.99/tCO_2 to \$13.72/tCO_2 when wind and solar are relied upon for meeting climate policy targets, but marginal costs rise rapidly from \$32.60/tCO_2 (\$41.00/tCO_2) for low solar (high solar) at a carbon price of \$50 to \$187.50/tCO_2 (\$193.80/tCO_2) at the highest carbon price.

When nuclear power is permitted in the system, the average cost rises to \$88.20/tCO_2 and the marginal cost to \$196.90/tCO_2 at the highest carbon price. However, when wind and/or solar energy enters the Alberta electricity grid, the maximum emissions reduction that can be achieved is about 56%, but, when nuclear power is permitted, emissions could be reduced by as much as 97%. This is seen in Fig. 4, which provides the estimated system-wide CO_2 emissions from generating enough electricity to meet the Alberta load in each hour. The difference between the solar and wind scenarios is almost indistinguishable, but entry of nuclear power at the higher carbon prices results in a very large drop in emissions.

Finally, the battery did not enter the model because it was considered too expensive. However, when we forced the Alberta grid model to rely only on renewable energy sources, a battery with a capacity of 10,917.5 MW and energy storage of 133.9 GWh was required. This

compares with the 'gigantic' 100 MW/129 MWh capacity battery installed to increase the reliability of the electricity grid in South Australia. The Tesla battery occupies about 0.1 km^2, so the battery required for Alberta would occupy between 1000 and 10,000 ha (depending on whether power or energy capacity determines battery size). The optimal desired battery capacity would change to 2535 MW/ 1113.3 GWh if baseload gas or nuclear power is permitted, because low-cost thermal generation can take advantage of storage, not intermittent renewables. The battery allows generating assets with the lowest operating costs to increase capacity above baseload, sending excess power to the battery when generation exceeds load.

4. Conclusions

Our results indicate that solar and wind are unable to replace two-thirds of lost coal-fired generation in Alberta as required by government policy. Added wind plus solar generation might replace at most one-third of lost coal capacity, but only 22% of the electricity previously produced by coal. The remainder would need to come from gas. Further, the maximum optimal capacity of intermittent renewables that might be worthwhile installing would not exceed 3000 MW (42% of lost coal capacity), and would not be worth undertaking unless the shadow price of carbon was greater than \$175/tCO_2; in that case, nuclear power would be a preferred option. Clearly, the optimal capacity of intermittent renewables that Alberta should install is much less than the 4200 MW projected by the AESO. Installing more capacity would simply be too costly and could well result in wasted renewables – electricity that is generated, regardless of the source, that would need to be dumped in some manner as it could not be used. Further, the results suggest that the 'missing money' problem worsens when comparing renewable energies with other sources in the absence of nuclear power.

The marginal cost of reducing CO_2 emissions rises sharply relative to the average cost as policy seeks to replace coal-fired power with renewable sources of energy. When comparing the average and marginal costs of reducing emissions for alternative energy sources, we found that the average and marginal costs of reducing emissions are about the same with renewable energies as with nuclear power; however, deployment of nuclear power can decrease CO_2 emissions by as much as 97% compared to only 56% with solar and wind. Further, nuclear energy will outcompete wind and solar for battery storage, although battery storage is not economic at this time. Further research into the use of storage in such a system analysis is warranted.

Finally, the model and approach employed in the analysis presented here are not to be confused with a practical/engineering approach that would require substantially more detail and include such things as transmission costs and congestion, appropriate siting of wind turbines and solar panels, and so on (see McWilliam et al., 2012). Indeed, our results are optimistic because the details of building and integrating intermittent energy sources into the grid are more nuanced than provided in our policy model. On the other hand, the results are impacted by changes in the load profile and, more importantly, wind and solar-radiation profiles; changes in any of these could improve or worsen the prospects for renewable energy. Unfortunately, the mix of generation assets that is chosen must of necessity be able to respond to the pessimistic and not the optimistic scenarios. Therefore, the results presented here must be considered to be optimistic when it comes to the challenge of eliminating coal-fired power.

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